10 November, 2010

General Remarks

The Climate Policy Initiative (CPI) welcomes the opportunity to respond to the Draft Framework Guidelines on Capacity Allocation and Congestion Management for Electricity (Ref: E10-ENM-20-03 dated 08 September 2010). For a secure, economic and sustainable operation of the European electricity network, it is vital that a consistent, transparent and timely approach is taken to integrate intra-day actions and congestion management.

Based on our analysis, we share the perspective of ERGEG that a nodal pricing approach is "the ultimate goal and … optimal solution"[1]. Hence we are surprised that this approach is not considered as the target model in the CACM guidelines. Many successful deregulated power markets[2] show that designs that do not address transmission constraints fully, or do not offer a consistent approach for integrating day-ahead and real-time energy trading, can be subject to market failures including gaming. Taking these international experiences into consideration we regard the proposed flow-based CACM only as a sub-optimal intermediary solution.

In light of the goals of European climate policy, the European power system will require significant investments in transmission, distribution, generation and innovative new approaches to manage the demand side. The intermediary character of the current proposal creates significant regulatory risk that undermines investment and innovation, as future changes to the regulation can be expected, but neither their timing nor exact nature is clear to market participants.

Specific Responses to Questions

General Issues

1. *Are there any additional issues and/or objectives that should be addressed in the Capacity Allocation and Congestion Management IIA and FG?*

Clearly, the European power market needs better coordination and optimisation mechanisms to integrate large volumes of supply-driven renewable energy generation (wind, PV) in a cost optimal way. Since wind forecasting accuracy improves significantly closer to real-time, actions on an intra-day timeframe are required with an increasing importance. This demands an integrated solution that will allow for the joint dispatch of generation and allocation of transmission capacity across Europe (see study results Smart Power Markets for Europe)[3].

2. *Is the vision of the enduring EU-wide target model transparently established in the IIA and FG and well suited to address all the issues and objectives of the CACM?*

[1] Page 30 – Initial Impact Assessment for the Framework Guidelines on Capacity Allocation and Congestion Management, Ref: E10-ENM-01-01-CM_FM_IIA

[2] Such as those in several US states. To resolve these market failures, these areas implemented a nodal pricing model which eventually extended from several northeastern US states to neighboring states; recently being adopted in Texas and California.

[3] Will be available on www.climatepolicyinitiative.org, or can be requested by email from the authors.

Sustained certainty of investment is a must, and can only be secured by adopting a long-term approach to market design. The proposed zonal pricing methodology falls short in dealing with effective congestion management and intra-day optimization of power systems.

We expect that increased renewable energy generation will require price zones to change frequently in a time and space dimension. Otherwise, TSOs will have to resort to inefficient and expensive redispatch actions to avoid intra-zonal congestions. Hence we feel that an integrated approach using nodal pricing should be considered an option by ERGEG.

3. *Should any of the timeframes (forward, day-ahead, intraday) be addressed in more detail?*

The interaction between forward, day-ahead and intraday markets is important to the design of the European power market. Different rules applied in different time frames create opportunities to game the market – as was vividly demonstrated in California's power crisis when more attractive options in real time led generators to only sell power in the real time market.

4. *In general, is the definition of interim steps in the framework guideline appropriate?*

It is unclear how the proposed approach contributes towards the achievement of a long-term sustainable power market fit for large-scale integration of renewables.

5. *Is the characterisation of force majeure sufficient? Should there be separate definitions for DC and AC interconnectors?*

Our understanding is that the proposed approach does not provide a consistent framework to deal with DC interconnectors (or FACTS devices) <u>within</u> a meshed network nor from an offshore grid that is connected to several points/countries in a meshed network.

To make effective use of advantages that technologies such as flexible DC systems and/or FACTS (Flexible AC Transmission Systems) can offer to the European power grid, they must be an integral part of the market design. For instance, an offshore grid connected to both Germany and the Netherlands can circumvent the declared constraint on transmission between the two countries, without necessarily addressing the underlying transmission constraints typically associated with lines within the countries.

Thus, TSOs either will further reduce the capacity they make available for on-shore transfers, or will incur additional costs for re-dispatch within their region. Such situations can contribute to incentives to design DC links that might not be desirable from a systems perspective.

6. *Do you agree with the definition of firmness for explicit and implicitly allocated capacity as set out in the framework guideline? How prescriptive should the framework guideline be with regard to the firmness of capacity?*

A core value the transmission network can offer to the European power system is the flexibility to balance large volatilities of wind power across several countries on short timeframes. With ambitious medium-term energy targets, many GWs of supply-driven, variable generation will be added to the existing network.

A suitable power market design needs to jointly allocate national and international transmission capacity whilst providing a platform to trade energy and balancing services on an intraday timeframe. This is only possible where transmission and energy markets are jointly cleared (e.g. implicit auctions, nodal pricing). In this case, the question of firm capacity does not arise as any contracts would be designed as financial transmission contracts.

7. *Which costs and benefits do you see from introducing the proposed framework for Capacity Allocation and Congestion Management? Please provide qualitative and if applicable also quantitative evidence.*

We are concerned that the consultation excludes a viable solution from the considerations as described in the Initial Impact Assessment. Please allow us to present our qualitative assessment of the options to address the intraday and congestion management issues. Further information can be obtained in due course on www.climatepolicyinitiative.org. Please also see our answer on **question 3** regarding institutional management.

The topology of the European power network does not follow national boundaries; significant congestion occurs both between and within countries.

Table 1 illustrates how the efficiency of the system can be enhanced by integrating congestion management and balancing markets on a European scale. Several market design options have been explored in the past to achieve some of this integration, but as the table outlines, only a locational marginal/nodal pricing approach has the potential to achieve full integration.

	(i) Joint allocation of international transmission rights	(ii) Integration with day ahead energy market	(iii) Integration with national congestion management	(iv) Integration with intraday/ balancing market
Bilateral NTC auction	No	No	No	No
Joint multi-country auction of NTC rights	Yes	Yes	No	No
Multi-region day-ahead market coupling	Possible	Yes	No	No
Locational marginal pricing/nodal	Yes	Yes	Yes	Possible

Table 1: Aspects of congestion management and balancing markets that benefit from European integration, and market design options to achieve this integration

Section 1.1: Capacity Calculations

8. *Is flow based allocation, as set out in the framework guideline, the appropriate target model? How should less meshed systems be accommodated?*

No. Please see our general remarks above.

9. *Is it appropriate to use an ATC approach for DC connected systems, islands and less meshed areas?*

See our answer to **question 5**.

10. *Is it necessary to describe in more details how to deal with flow-based and ATC approach within one control area (e.g. if TSO has flow-based capacity calculation towards some neighboring TSOs and ATC based to the others)?*

It would be helpful to understand how ERGEG proposes TSOs/ISOs determine their ATC values without fully comprehending neighbouring country national congestions.

Our understanding is that no harmonization method exists that provides a transparent calculation of ATCs (as mentioned in our answer to **question 8**). The absence of such a methodology means that TSOs/ISOs have a strong incentive to understate ATC values in order to limit international flows that could contribute to congestion within their respective network.

This argument is further reinforced by TSOs/ISOs being exposed to implicit/explicit incentives to limit redispatch costs. Thus, the current approach appears to inhibit the effectiveness of the existing European network to balance wind power and/or trade energy across country borders.

11. *Is it important to re-calculate available capacity intraday? If so, on what basis should intraday capacity be recalculated?*

Yes, it is important, but as mentioned in our answer to **question 10**, no methodology exists that allows for the fair balancing of international flows within the European grid.

Section 1.2: Zone delineation

12. *Is the target model of defining bidding zones on the basis of network topology appropriate to meet the objectives?*

In our analysis[4] evaluating inefficiencies of the current capacity allocation mechanism compared with a nodal pricing arrangement, we struggled to identify zones in the European network with a homogenous price. Instead, on a nodal level, prices constantly changed with a shifting demand and supply profile.

[4] In final stages – please contact us for more information.

This reflects the point that congested interfaces change with dispatch patterns. Furthermore, empirical evidence of this challenge was gathered in the US states that ultimately moved towards a nodal price regime.

We fear that an inappropriate definition of 'zones', which subsequently needs changing at a later date, creates substantial investment risks for market participants, as they struggle to anticipate future zoning and do not have Financial Transmission Rights (FTRs) available to hedge locational price differences that would result from their energy trading.

13. *What further criteria are important in determining the delineation of zones, beyond those elaborated in the IIA and FG?*

See above.

Section 2: Forward markets

14. *Are the preferred long-term capacity products as defined in the framework guideline suitable and feasible for the forward market timeframe?*

Regarding Physical Transmission Rights (PTRs): with an increasingly volatile flow pattern (largely from significant wind power integration) it will be difficult/inefficient to exactly match transmission volumes with PTRs.

i. Hence, FTRs provide a preferable solution. Issuing FTRs reduces the volatility of revenue streams of the TSO/ISO because the FTR effectively provides a claim on congestion revenue. It is essential for the TSO/ISO to issue FTRs within available transmission capacity. Also, where flow patterns are dominant in one direction, it would be difficult/costly to find sufficient counterparties to issue such FTRs (and bear the full risk without the opportunity to hedge

15. *Is there a need to describe in more detail the elaborated options for the organisation of the long-term capacity allocation and congestion management?*

The emphasis of regulators should be on designing effective day-ahead and intraday markets, and transparent auctions or allocations for FTRs.

Beyond this, the market might be more suitable to establish the necessary long-term products and platforms for energy trading.

Section 3: Day-ahead allocation

16. *Are there any further issues to be addressed in relation to the target model and the elaborated approach for the day-ahead allocation?*

A consistent approach to day-ahead and congestion management is required – please see answers above.

Section 4: Intraday allocation

17. Are there any further issues to be addressed in relation to the target model and the elaborated approach for the intraday allocation?

An approach that provides consistency between day-ahead, intraday and real time markets and integrates congestion management and energy markets is required – please see answers above.

18. Does the intraday target model provide sufficient trading flexibility close to real time to accommodate intermittent generation?

The forecast error for wind decreases distinctly with a shorter lead-time. In markets unable to adapt to changing wind forecasts during the day, large volumes of real-time balancing are required. Furthermore, because of high uncertainty of wind 24-36 hours ahead of physical feed-in, a significant amount of balancing reserve capacity is required.

System costs for balancing wind uncertainty can be significantly reduced if an improved market design allows for optimisation of dispatch across the entire system, based on wind forecasts with lead-times reduced to 1-4 hours ahead of physical dispatch. For example, Spain succeeded to keep demand for balancing services constant despite the large increase in wind deployment and the almost 'island' nature of the grid. This shows that at the European scale an integrated approach to congestion management, intra-day, and balancing markets can reduce costs and avoid delays for large scale renewable integration.

The following table summarises how different market design options allow for intraday optimisation of the power system in the presence of wind power, and how they perform against criteria used for their evaluation:

	Dispatch adjusted during day	**Balancing requirements / provision adjusted during day**	**Flexible use of individual conventional power stations**	**International integration of intraday/ balancing markets**	**Effective monitoring of market power possible**
UK system	◔	◔	◔	✗	◔
German system	◐	✗	◔	◔	◔
Nordpool	◐	◐	◔	◐	◔
Spanish system	●	◐	●	✗	◐
PJM type system	●	●	●	◕	●